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Article

Performance ratio and degradation rate analysis of 10-year field exposed residential photovoltaic installations in the UK and Ireland

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Abstract: As photovoltaic (PV) penetration of the power grid increases, accurate predictions of return on investment require accurate analysis of decreased operational power output over time. Degradation rate in PV module performance must be known in order to predict power delivery. This article presents the degradation rate over 10-years for seven different PV systems located in England, Scotland, and Ireland. It was found that the lowest PV degradation rate of -0.4% to -0.6 %/year is obtained in the Irish PV sites. Higher PV degradation rate of -0.7% to -0.9%/year is found in England, whereas the highest degradation rate of -1.0%/year is observed in relatively cold areas including Aberdeen and Glasgow, located in Scotland. The main reason that the PV systems affected by cold climate conditions had the highest degradation rate is due to the frequent hoarfrost and heavy snow affecting these PV systems, which considerably affects the reliability and durability of the PV modules and their performance. Additionally, in this article, we analyse the monthly mean performance ratio (PR) for all examined PV systems. It was found that PV systems located in Ireland and England are more reliable compared to those located in Scotland.

Keywords: Renewable Energy; Photovoltaics; Degradation; Reliability Analysis

1. Introduction

The ability to precisely predict the output power delivery over time is of vital importance to the growth of the photovoltaic (PV) industry. Two key cost drivers are the efficiency with which sunlight is converted into actual energy and how this relationship fluctuates over time. Accurate quantification of power output decay over time, also known as degradation rate [1], is critical to all stakeholders'/utility companies, investors, integrators, and researchers alike. Economically, PV modules degradation rate are equally important, because a higher degradation rate interprets directly into reduced output power produced by the system, thus reduces future cash flows [2].

Inaccuracies in determining degradation rate lead to amplify financial risks in the PV sector. Technically, degradation mechanisms are essential to understand because they could ultimately lead to PV system failures [3]. Typically, a 10% decline is considered a failure. However, there is no compromise on the definition of failure [4], because a high-efficiency module degraded by 50% may still have a higher efficiency than a non-degraded module from a less efficient technology.

The documentation of the degradation mechanisms through modelling and experiments in principle directly leads to lifetime improvements of PV modules, as suggested by S. Kawai *et al.* [5]. Outdoor field-testing has played a significant role in measuring long-term lifetime and behaviour for at least two reasons: it is the typical functioning environment for PV installations, and it is the only way to correlate indoor testing apparatuses to outdoor results to forecast field performance.

Up to date, there is a lack of published work found in the literature which represents the analysis of PV degradation rate across the United Kingdom. Therefore, in this article, the degradation rate of seven PV systems installed in various locations in the UK were examined and comprehensively compared over a period of ten years (2008 to 2017). Before moving to the methodology section, it is indeed important to have an overview of the degradation rate across different regions in the world, summarized as follows:

United States of America (USA): The USA is among the head five countries leading the PV technology worldwide [6]. In 1977, the Department of Energy established the Solar Energy Research Institute in Golden, Colorado. Outdoor testing of modules and sub-modules started at the Solar Energy Research Institute in 1982. When amorphous silicon (a-Si) modules first became commercially available, NREL began to report the degradation rate that was considerably higher than -1.0%/year [7]. In [8] and [9], similar results of the PV degradation were found in small (<10 kWp) size PV installations, followed by a yearly degradation rate of approximate -0.8 to -1.25%/year.

Europe: The terrestrial focus of the PV industry in Europe can be traced to the oil crisis of the 1970s. The development and installations of PV sites can be classified into publicly and privately funded projects. The publicly-funded part in Europe can be additionally classified into the umbrella organization of the Commission of the European Communities and individual national programs. Never the less, various references indicate that the annual degradation rate in Spain and Italy is between -0.8% to -1.1%/year [10] – [12], in Germany between -0.5% to -0.7%/year [13] and [14], in Cyprus between -0.8% to -1.1%/year [15], in Greece between -0.9% to -1.13%/year [16], and finally in Poland is always higher than -0.9%/year [17].

Asia: Chandel *et al.* [18] studied the degradation rate in India based on a PV system operated for a period of 28 years. Based on their analysis, it was found that the degradation rate is equal to -1.4%/year. Similar results found by Dubey *et al.* [19], where the degradation rate in southern India is observed at -1.25%/year. Furthermore, in Thailand, the degradation rate was widely different, ranging between -0.5% to -4.9%/year [20]. However, C. Dechthummarong *et al.* [21] found that the degradation rate based on 15 years of PV operation in northern Thailand is equal to -1.5 %/year. The degradation rate of PV modules in many other countries such as Japan, Singapore, and Republic of Korea are reported in [22] – [24], the PV degradation rate is equal to -1.2%/year in Japan [22], -2.0%/year in Singapore [23], and -1.3%/year in the Republic of Korea [24].

In summary, as a global point of view, the PV degradation rates varies from -0.2% to -2.0%/year. Yet there is not enough evidence on the annual PV degradation rate in the region of the UK and Ireland. Therefore, this study aims to fill in this gap of knowledge by evaluating seven different PV systems located in various locations (England, Scotland, and Ireland). It was found that the average annual degradation rates of the PV installations vary between -0.4% to -1.16%/year, contingent on the environmental conditions.

2. Methodology

2.1. Description of the Examined PV systems

In this work, seven different PV installations were examined. The geographical distribution of the PV systems is shown in Figure 1a and summarized in Table 1. Figure 1b presents a real picture of the examined PV system located at Huddersfield (PV site C). All examined PV systems have an identical configuration which is demonstrated in Figure 1c, as well as identical azimuth (-3° due to South) and tilt angle of (39°). The PV installations comprise crystalline silicon PV modules with peak power of 220 W, and they are configured in 2 PV strings connected in parallel, each comprises 9 PV modules connected in series. All have the same PV capacity of 3960 W. The electrical characteristics, including the peak power, voltage and current at maximum power point for the examined PV modules, are shown in Table 2.

In the UK and Ireland, the dominant PV installations are made of crystalline silicon. For that reason, in this study, we aim to analyse the performance of crystalline silicon PV installations made of the same configuration, manufacture, and connected via a similar electrical component.

Table 1. Distribution of the Examined PV Systems

PV site	Location	UK	Ireland
A	Plymouth, England	✓	-
B	London, England	✓	-
C	Huddersfield, England	✓	-
D	Glasgow, Scotland	✓	-
E	Aberdeen, Scotland	✓	-
F	Dublin, Ireland	-	✓
G	Sligo, Ireland	-	✓

Furthermore, all observed PV systems are fitted with ICONICA maximum power point tracking (MPPT) unit. This device has the capability of enhancing the output power during partial shading conditions, the MPPT efficiency ranging from 97.5% to 99.2%. The MPPT unit is connected to a hybrid, pure sine wave inverter linked to the grid, and the inverter efficiency is ranging from 90% to 94%.

The tested PV systems are categorized into three main groups; the first group contains PV sites A, B and C (located in England), second group comprises PV sites E and F (located in Scotland), the last group consists of two PV sites F and G (located in Ireland).

The solar irradiance (G) and ambient temperature (T) play a significant role in the performance and annual energy production for the PV modules. Since the examined PV sites are in different locations, it is worthy of addressing the locations weather and ambient temperature data. The average values of the irradiance and ambient temperature in all studied locations between the years 1981 – 2010 is taken from [25] and presented in Figure 1a.

All examined PV systems sited with a weather station. The weather station measures the ambient temperature, wind speed, humidity, and solar irradiation. Onsite measurements of dc voltage and current are recorded by the maximum power point (MPPT) units, and at the inverter input sampled every 5 min; thus, the number of samples collected in each year is equal to 52,560 samples. The comparison between degradation rates of the PV systems are observed over a period of 10 years; 2008 to 2017.

Table 2. PV Module Electrical Characteristics

PV module parameter	Value
PV peak power	220 W
Voltage at maximum power point (V_{mpp})	28.7 V
Current at maximum power point (I_{mpp})	7.67 A
Open Circuit Voltage (V_{oc})	36.74 V
Short Circuit Current (I_{sc})	8.24 A

2.2. Power-Irradiance Analysis Technique

The Power-Irradiance technique is a method which compares the output measured power of a PV system with a corresponding irradiance level; usually full spectrum 0 to 1000 W/m^2. This technique depend on on the measured and simulated/theoretical output power of the examined PV system in order to visualize the degradation rate of the PV systems. It is worth noting that partial shading, hot-spots, micro-cracks, and other environmental factors are not considered while estimating the theoretical output power.

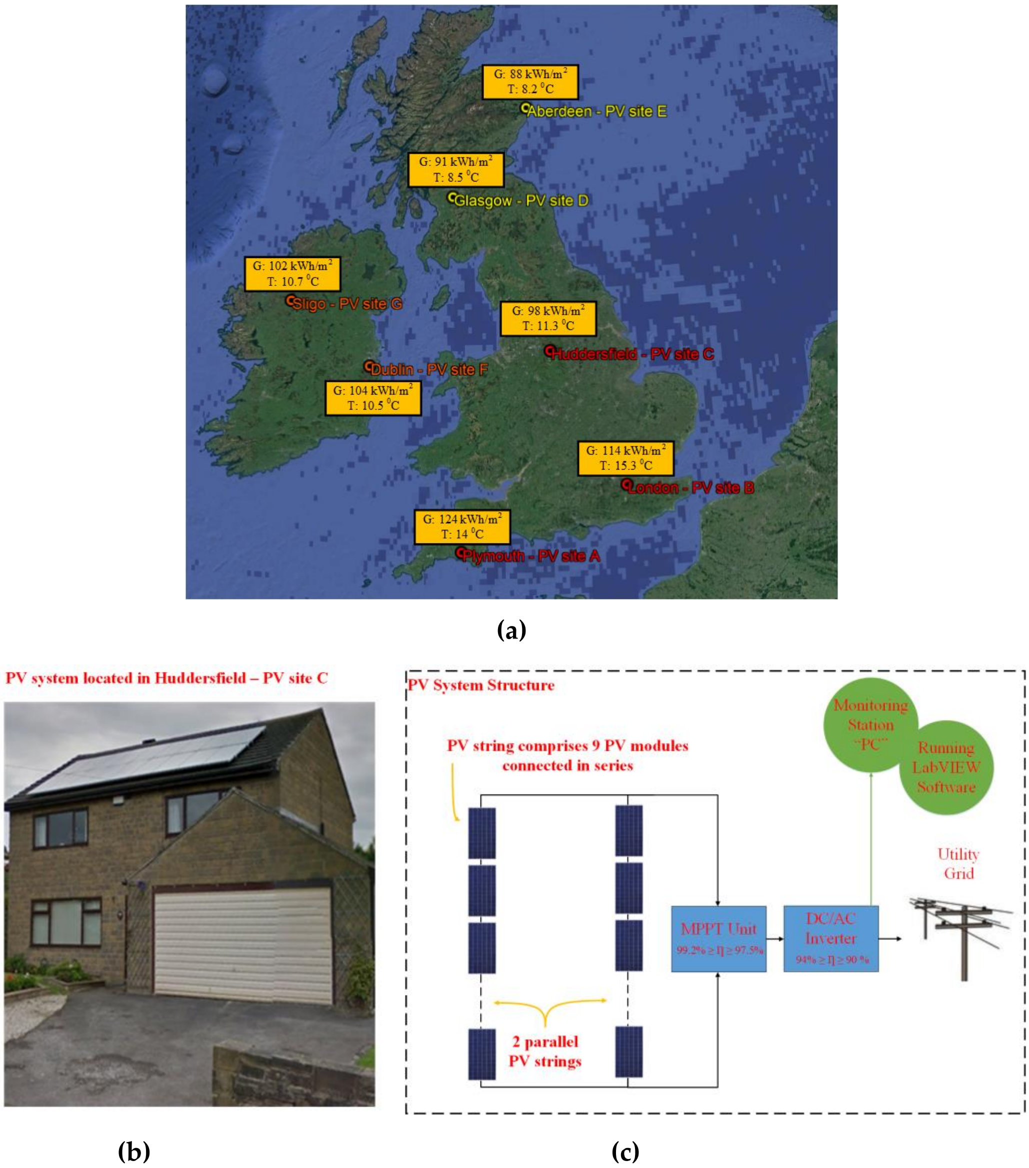


Figure 1. Examined PV systems configuration and its geographical representation: (**a**) Geographical distribution of the examined PV installations in the United Kingdom including the average irradiance (G) and temperature (T) over the last 30 years; (**b**) Real picture of the examined PV system installed at Huddersfield site – PV site C; (**c**) PV sites configuration that comprises two parallel PV string each consists of nine series connected PV modules.

The calculation of the theoretical power of the PV installations $Pdc_{theoretical}$ is determined using Eqs. (1) - (3), where the theoretical power depends on the measured plane-of-array irradiance G, and the PV module temperature T_c.

The results of the irradiance vs output power are presented using a full spectrum of the irradiance; 0 to 1000 W/m^2. However, in the analysis of the degradation rate, mainly using Eq. (2), the only irradiance from 250 W/m^2 to 1000 W/m^2 was considered. Because during the determination of the degradation which will be discussed later in the results section, at low irradiance values the slope of the power-irradiance would be expected to deviate; hence, resulting in inaccurate analysis of the degradation rate.

$$Pdc_{theoretical} = N_{sm} . N_{pm} . Pm_{theo} . G_{eff} . (1 + K_v . \Delta T) . (1 - K_i . \Delta T) \quad (1)$$

$$G_{eff} = \frac{G}{G_n} \quad (2)$$

$$\Delta T = T_c - T_n \quad (3)$$

where N_{sm} and N_{pm} are the number of PV modules connected in series and parallel respectively, the Pm_{theo} is the measured peak power of the PV module under standard test conditions (STC), K_v and K_i are the voltage and current temperature coefficients respectively, these coefficients provided in the PV modules manufacturer datasheet. The last parameters, G_n and T_n are the reference irradiance and PV module temperature under STC (G: 1000 W/m^2, and T: 25 °C).

Linear regression equations are obtained using a Linear Correlation Approach (LCA) from the actual PV array dc output measured power for each year described by the following empirical Eq. (4).

$$P_{dc\ measured} = A_{Gr} \,.\, G + C \quad (4)$$

where $P_{dc\ measured}$ is the actual PV installations dc output measured power, A_{Gr} is the gradient, G is the plane of-array irradiance measured by the weather station, and C is the ordinate value of the $P_{dc\ measured}$ at G = 1000 W/m^2.

3. Results

3.1. Degradation Rate in England

The power-irradiance technique was applied to evaluate the degradation rate of the examined PV systems based on their dc output power. Figure 2 shows the power-irradiance profiles in three different years: 2008, 2013, and 2017. The blue points present the theoretical dc power obtained from Eqs. (1) – (3), whereas the orange points present the actual measured dc power.

Furthermore, Table 3 summarizes the yearly and total degradation rates of the examined PV systems. It was found that PV systems A and C had the highest degradation rate during the first year of operation; in 2008. Whereas, PV site B, located in London, had the highest yearly degradation rate of -0.95% in 2012.

Table 3. England PV systems Degradation Rate

Year	Plymouth Site A		London Site B		Huddersfield Site C	
	Yearly	Cumulative	Yearly	Cumulative	Yearly	Cumulative
2008	**-0.91**	**-0.91**	**-0.87**	**-0.87**	**-0.73**	**-0.73**
2009	-0.71	-1.62	-0.85	-1.72	-0.55	-1.28
2010	-0.72	-2.34	-0.88	-2.6	-0.42	-1.7
2011	-0.73	-3.07	-0.80	-3.4	-0.58	-2.28
2012	-0.77	-3.84	-0.95	-4.35	-0.55	-2.83
2013	**-0.73**	**-4.57**	**-0.92**	**-5.27**	**-0.47**	**-3.3**
2014	-0.71	-5.28	-0.88	-6.15	-0.53	-3.83
2015	-0.73	-6.01	-0.85	-7.0	-0.43	-4.26
2016	-0.69	-6.7	-0.87	-7.87	-0.53	-4.79
2017	**-0.75**	**-7.45**	**-0.93**	**-8.8**	**-0.51**	**-5.3**
Average	**-0.74%/year**		**-0.88%/year**		**-0.53%/year**	

As can be noticed in Figure 2 and Table 3, there is almost a linear degradation rate for PV site A. The average degradation rate over the last ten years is equal to -0.74%/year. The highest average degradation rate is observed in site B at -0.88%/year. The PV system installed in Huddersfield (PV site C) has the minimum degradation rate compared to PV sites A and B; its annual degradation rate is equal to -0.53%/year.

Another interesting observation found from the reported results in Table 3 that PV systems A and B, which are located in areas with relatively hot weather conditions have more degradation rates compared to the PV system installed in Huddersfield, which is located in a relatively cold area. On the other hand, in order to study the correlation between the degradation rates vs the environmental conditions, the next sub-section will evaluate the degradation rates of two different PV installations located in cold weather conditions (sited in Scotland).

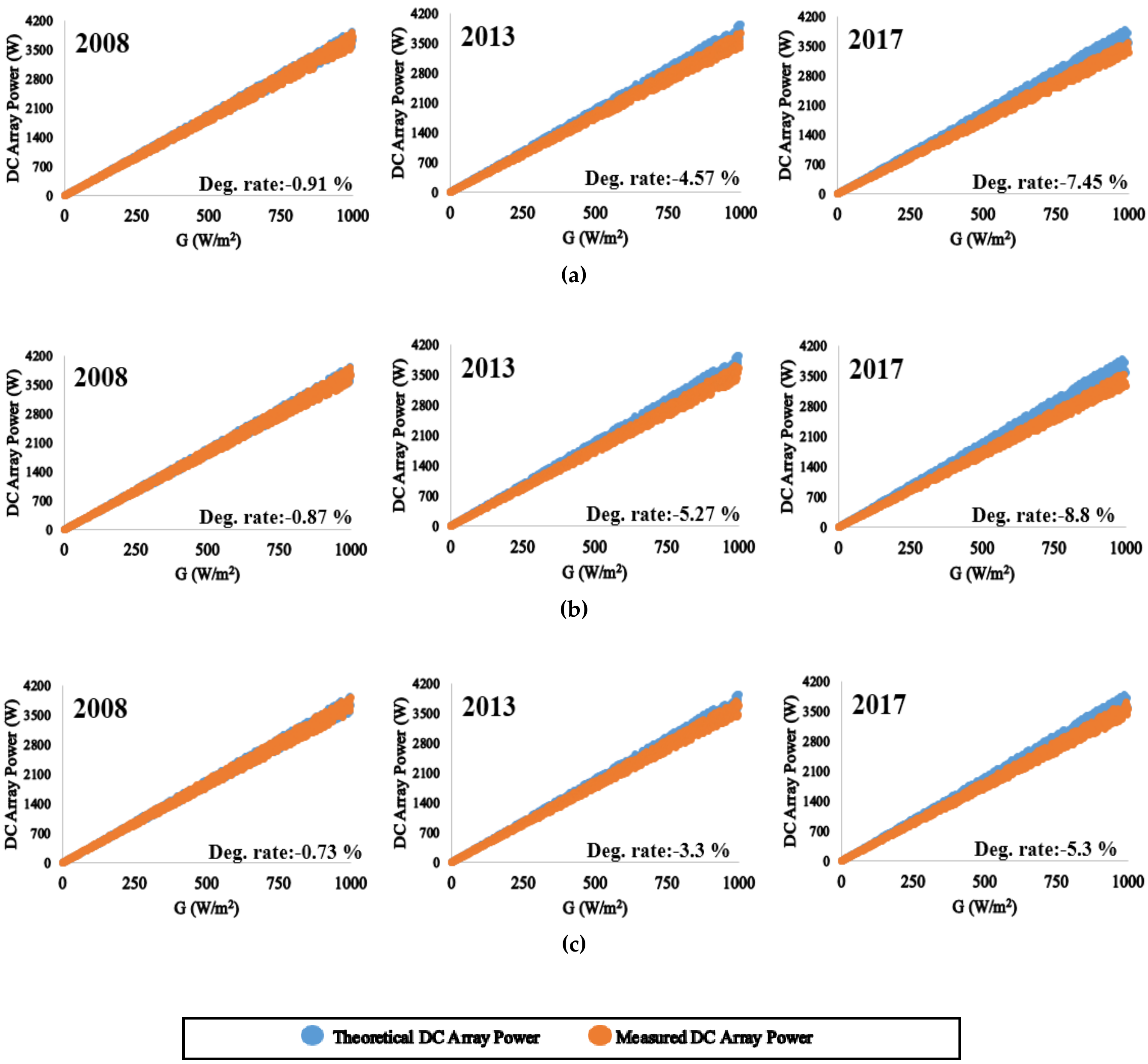


Figure 2. Cumulative degradation rate for PV systems A, B, and C in 2008, 2013, and 2017: (**a**) PV site A – Plymouth; (**b**) PV site B – London; (**c**) PV site C – Huddersfield.

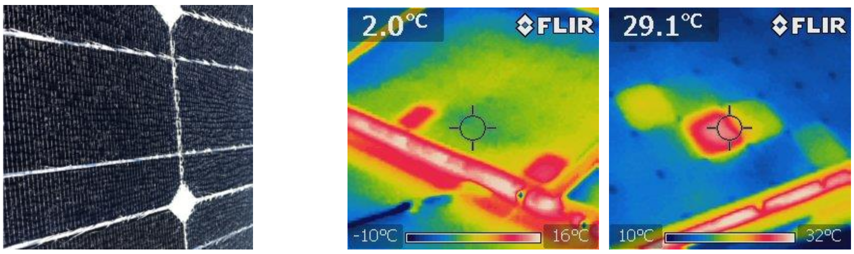
3.2. Degradation Rate in Scotland

The annual and cumulative degradation rate from 2008 to 2017 for both sites D and E are presented in Table 4. It is evident that both PV sites had a maximum degradation rate in their first year of operation "2008", the degradation rate is equal to -1.23% and -1.33% for site D, and E, respectively. The power-irradiance profile in 2008, 2013, and 2017 for both PV systems are shown in Figure 4. The degradation rate for the PV modules increases over the years. For example, in site D, the accumulative degradation rate increased from -1.23% to -10.59% from 2008 to 2017. However, there is a further reduction in the annual output power in Aberdeen compared to Glasgow. The degradation rate for Aberdeen PV system in 2008 is equal to -1.33%, and it increased to an accumulative of -11.62% in 2017.

Table 4. Scotland PV systems Degradation Rate Analysis

Year	Glasgow "Site D"		Aberdeen "Site E"	
	Yearly	Cumulative	Yearly	Cumulative
2008	**-1.23**	**-1.23**	**-1.33**	**-1.33**
2009	-1.15	-2.38	-1.19	-2.52
2010	-1.12	-3.5	-1.15	-3.67
2011	-1.08	-4.58	-1.22	-4.89
2012	-1.11	-5.69	-1.12	-6.01
2013	**-0.93**	**-6.62**	**-1.05**	**-7.06**
2014	-1.02	-7.64	-1.16	-8.22
2015	-0.92	-8.56	-1.15	-9.37
2016	-0.95	-9.51	-1.08	-10.45
2017	**-1.08**	**-10.59**	**-1.17**	**-11.62**
Average	**-1.05%/year**		**-1.16%/year**	

Remarkably, it was found that the yearly average degradation rate for Glasgow and Aberdeen PV installations are equal to -1.05% and -1.16%/year, respectively. This high degradation rate is related to the fact that both PV sites are in cold areas. The increase in the degradation rate is due to the effect of the heavy snow, rain, and high wind speed on the surface of the PV modules, thus there is a higher risk for PV hot spots [25], micro cracks [26] and [27], and damage in the surface of the PV modules. Figure 3a shows an actual image of broken glass for a PV module located in Aberdeen site due to hoarfrost (this image was captured in February 2018), whereas in Figure 3b two hot spots were observed in Glasgow PV system (these images were captured in June 2018). Therefore, in comparison to the degradation rates observed in the PV systems located in England, the PV systems located in Scotland had a higher degradation rate over the studied period.



(a) **(b)**

Figure 3. Example for the Impact of hoarfrost and heavy snow on PV modules: (**a**) PV module glass damage observed in Aberdeen site (PV site E) due to a hoarfrost weather condition; (**b**) Hot spots captured in two different PV modules in Glasgow site (PV site D) after a heavy snow weather condition.

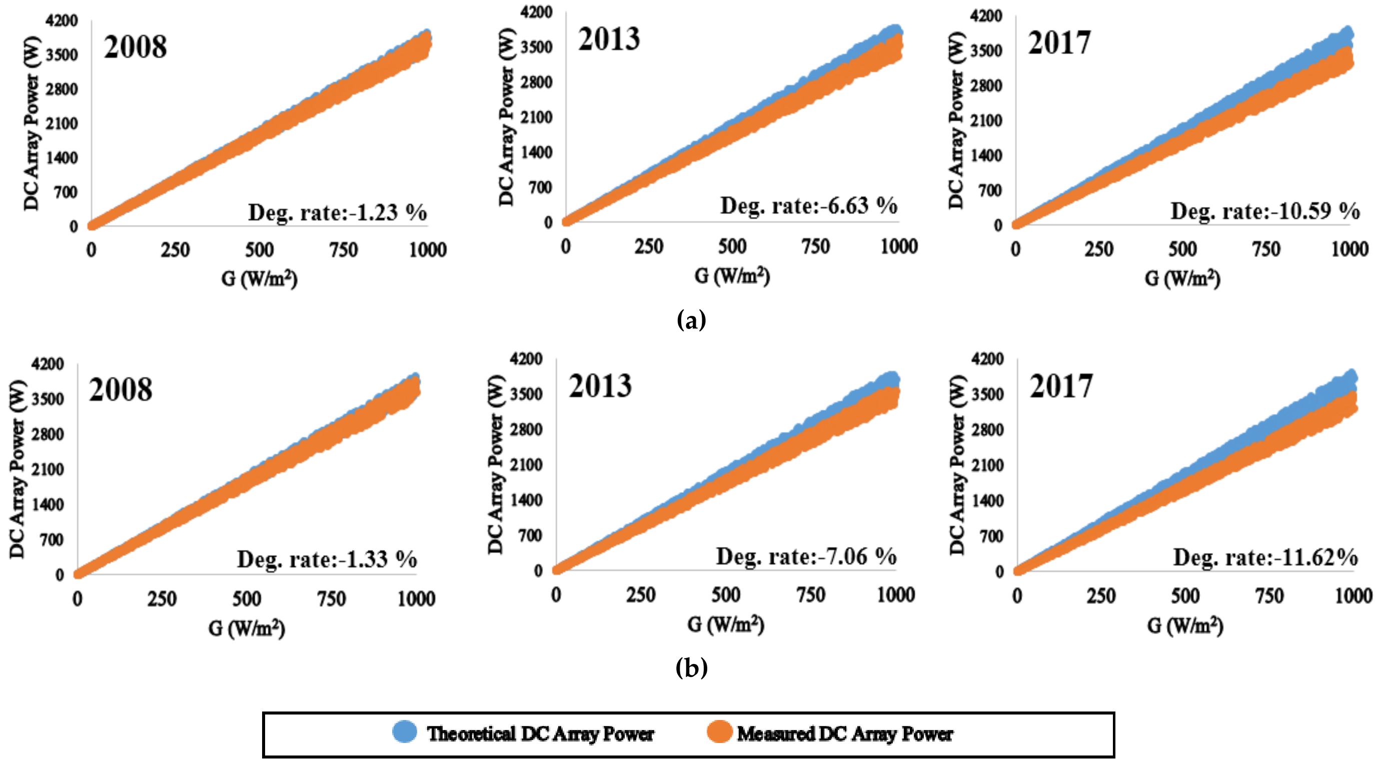


Figure 4. Cumulative degradation rate for PV systems D and E in 2008, 2013, and 2017: (**a**) PV site D – Glasgow; (**b**) PV site E – Aberdeen.

3.3. Degradation Rate in Ireland

The annual and cumulative degradation rate for site F and G are presented in Table 5. It is evident for both PV sites have a maximum degradation rate in their first year of operation "2008" which is equal to -0.69% and -0.72%, respectively. The power-irradiance profile in 2008, 2013, and 2017 for both PV sites are shown in Figure 5. The degradation rate for the PV modules increases over the years. For example, in site F, the accumulative degradation rate increased from -0.69% to -5.58% from 2008 to 2017. However, there is more loss in the annual output power in the PV systems located in Sligo, where the degradation rate for this site in 2008 is equal to -0.72%, and it increased to an accumulative of -5.8% in 2017.

The yearly average degradation rate for both Irish PV installations is equal to -0.56 and –0.58 %/year, respectively. Remarkably, the average yearly degradation rate for PV sites F and G over the last ten years is almost equal to the PV site C (located in Huddersfield). This result indicates that the weather conditions play a significant role in the degradation rates for PV modules. For example, PV systems located in Huddersfield, Dublin and Sligo relatively have the same degradation rate of the last ten years, where these locations are affected by the same irradiance and ambient temperature. By contrast with this result, it is possible to divide the cumulative degradation rate of all examined PV sites based on the weather conditions as follows:

- **UK-Based hot climate conditions:** Plymouth and London PV systems. The yearly average PV degradation rate is between -0.70% to -0.9%/year.
- **UK-Based average climate conditions:** Huddersfield, Dublin, and Sligo PV systems. The yearly average PV degradation rate is between -0.4% to -0.6 %/year.
- **UK-Based cold climate conditions:** Glasgow and Aberdeen PV systems. The yearly average PV degradation rate is always higher than -1.0%/year.

According to the literature review summary on page 2, our results indicate that PV installations in the UK and Ireland have relatively identical degradation rate compared to other counties affected by similar climate conditions. For example, in Germany [13] and Poland [17], the PV degradation rates are in the range of -0.5% to -1.5%/year, compared with our PV degradation results of -0.4 to -1.16%/year.

Table 5. Ireland PV systems Degradation Rate

Year	Dublin "Site F"		Sligo "Site G"	
	Yearly	Cumulative	Yearly	Cumulative
2008	**-0.69**	**-0.69**	**-0.72**	**-0.72**
2009	-0.55	-1.24	-0.58	-1.3
2010	-0.52	-1.76	-0.57	-1.87
2011	-0.53	-2.29	-0.57	-2.44
2012	-0.61	-2.9	-0.57	-3.01
2013	**-0.62**	**-3.52**	**-0.55**	**-3.56**
2014	-0.53	-4.05	-0.53	-4.09
2015	-0.48	-4.53	-0.53	-4.62
2016	-0.54	-5.07	-0.59	-5.21
2017	**-0.51**	**-5.58**	**-0.62**	**-5.83**
Average	**-0.56%/year**		**-0.58%/year**	

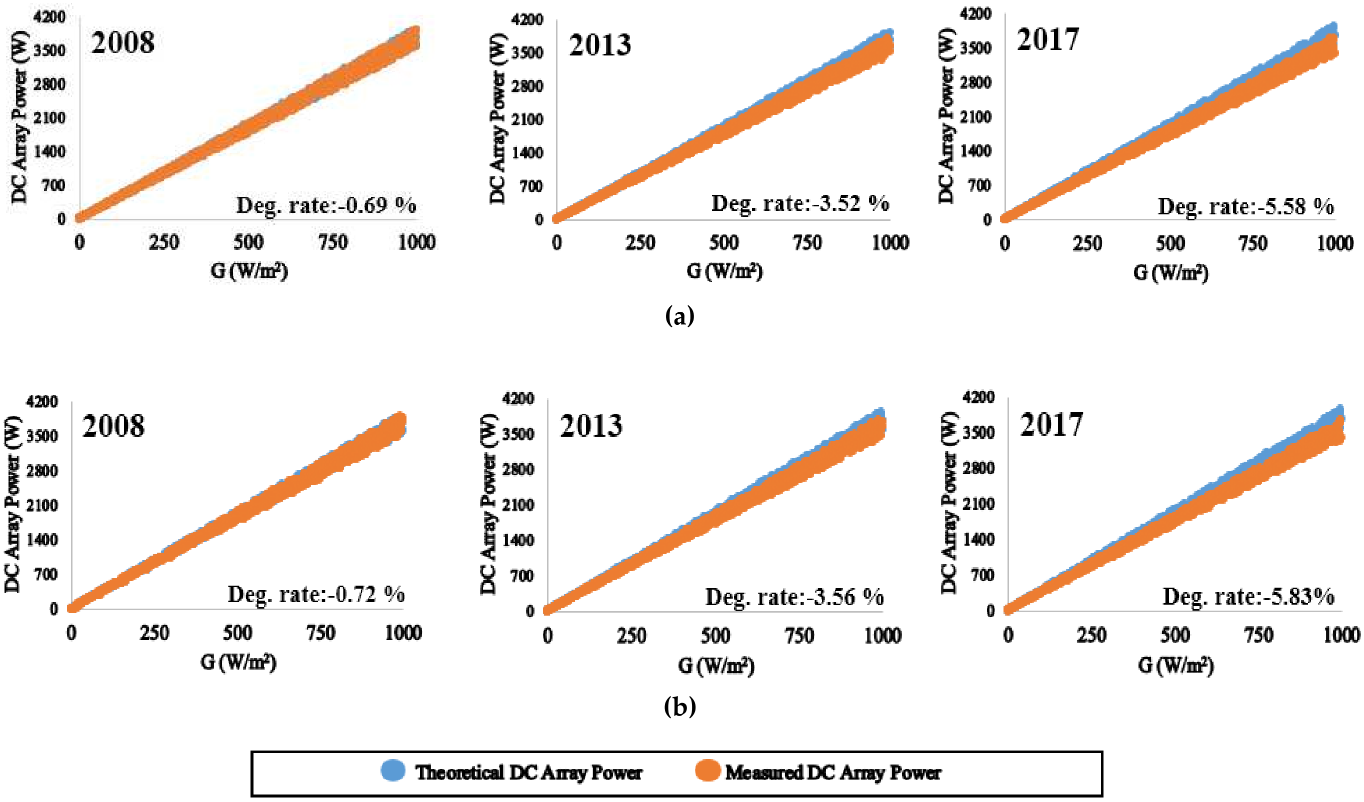


Figure 5. Cumulative degradation rate for PV systems F and G in 2008, 2013, and 2017: (**a**) PV site F – Dublin; (**b**) PV site G – Sligo.

4. Monthly Performance Ratio (PR) Analysis

In this section, the evaluation of the examined PV installations will be assessed using the performance ratio (PR) analysis. The PR is a widely used metric for comparing the relative performance of PV installations whose technology, capacity, design, and location differ [28] and [29]. The PR is calculated using (5).

$$PR = \frac{\eta_{measured}}{\eta_{theoretical}} = \frac{\frac{E}{G}}{\eta_{theoretical}} \quad (5)$$

where $\eta_{measured}$ and $\eta_{theoretical}$ are the actual measured efficiency and theoretical output efficiency of the examined PV installations, E is the output energy of the PV system (kWh), and G is the solar irradiance incident in the plant of the PV array (kWh).

The normal distribution graphs of the monthly PR for all examined PV systems are shown in Figure 6. The total number of samples is equal to 120 per location (twelve months × ten years of PV operation). The shape of the obtained results is categorized by a normal distribution function, whereas the mean corresponds to the monthly mean of the PR over the studied period.

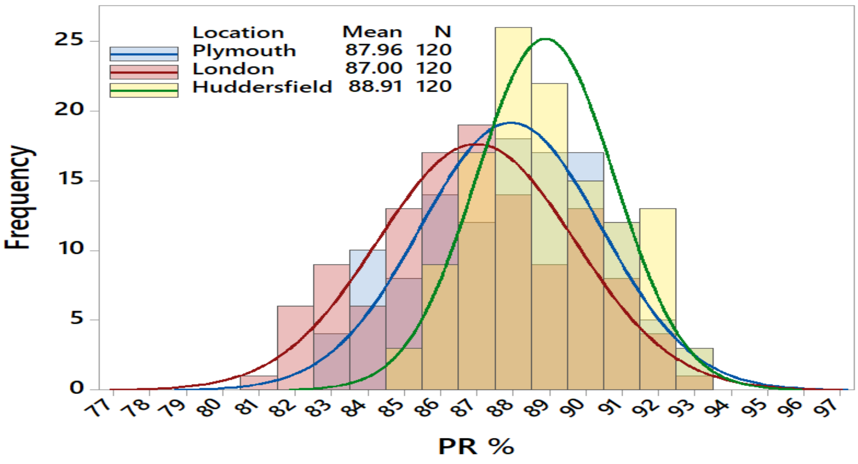
Figure 6a presents the PR of the PV systems installed in England. The mean PR value is equal to 88.91%, 87.96%, and 87% for PV systems installed in Huddersfield, Plymouth, and London, respectively. This result is consistent with the results obtained by the Power-Irradiance technique described earlier in section 3.1. Huddersfield PV system has the lowest annual degradation rate of -5.03%/year, while the highest PV degradation rate of -0.88%/year is observed for the PV system located in London.

According to Figure 6b, PV systems in Scotland had the lowest PR ratio compared to all other examined PV systems, the monthly mean PR are equal to 86.15% and 85.46% for Glasgow and Aberdeen, respectively. This result is due to the high degradation rate of these PV systems; their annual degradation rate was always higher than -1.0%/year. This result also confirms that PV hot-spotting, heavy snow, and the hoarfrost affects the PR ratio of the entire PV systems installed in cold areas [32].

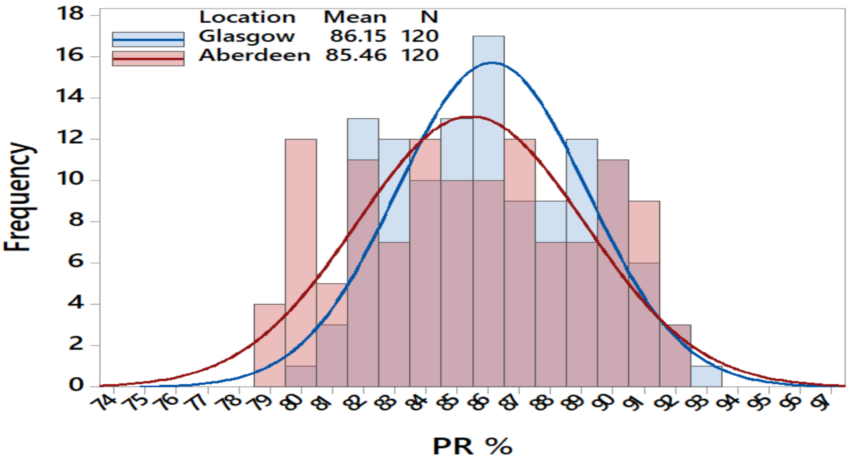
In the previous sections, we have demonstrated that the PV systems installed in Huddersfield, Dublin, and Sligo had almost identical annual degradation rates, varying from -0.53%/year in Huddersfield, -0.56%/year in Dublin, and -0.58%/year in Sligo. Consequently, according to results shown in Figure 6 a,c, the PV systems have nearly identical monthly mean PR ratios. In Huddersfield, it is equal to 88.91%, while in Dublin and Sligo, the monthly mean PR is equal to 88.78% and 88.57%, respectively.

In summary, this section confirms that the PV systems located in Ireland and England have better performance compared to both PV systems located in Scotland. Based on the technical report done by J. Leloux *et al.* [30], it was found that the monthly mean PR ratio of 5835 rooftop PV systems located in the UK is ranging from 81% to 83%. While, according to our findings, it was found that the monthly mean PR is always higher than 85%, there are two critical features of the higher rate of the PR observed in our study:

- All examined PV systems are fitted with efficient MPPT units. As was shown in Figure. 1c, these MPPT units have tracking efficiency ranging from 99.2% to 97.5%. Hence, the MPPT increases the annual yielded energy of the PV systems [33], particularly during partial shading scenarios, resulting in a higher PR ratio.
- One of the leading causes of output power loss in the PV systems is the conversion ratio of the dc-ac inverters, since they usually operate at low conversion limits, varying from 70% to 95% [31]. This is not a problem in our examined PV installations, since as noticed earlier in Figure. 1c, the PV systems are fitted with an efficient dc-ac inverter, with a conversion ratio always higher than 90%.



(a)



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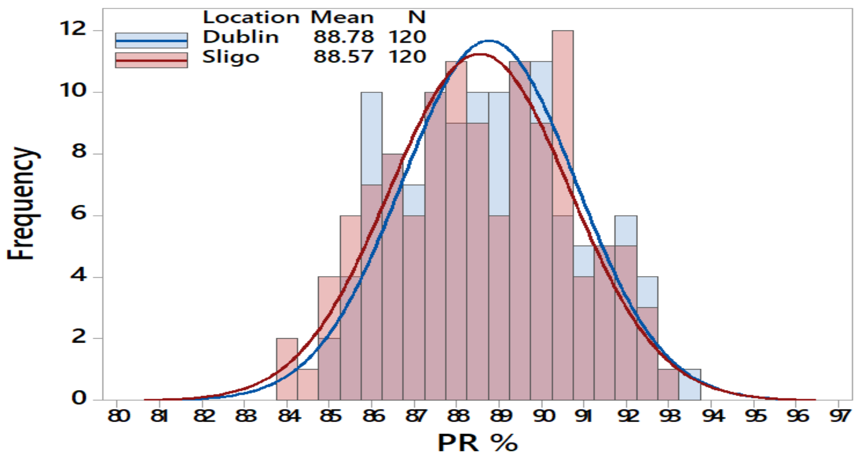


(c)

Figure 6. Performance Ratio (PR) analysis for all examined PV systems: (**a**) PV Systems installed in England; (**b**) PV systems installed in Scotland; **(c)** PV Systems installed in Ireland.

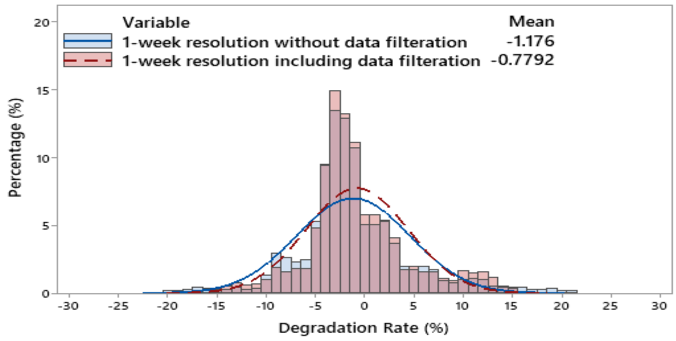
5. Summary of contributions

In this article, we presented a fundamental and straightforward approach to estimate the degradation rate in a typical PV installation. In order to compare the novelty and simplicity of our approach, the results of the degradation rate of Plymouth city was validated on a different, widely used, the degradation estimation technique of RdTool [34] developed by the national renewable energy laboratory (NREL).

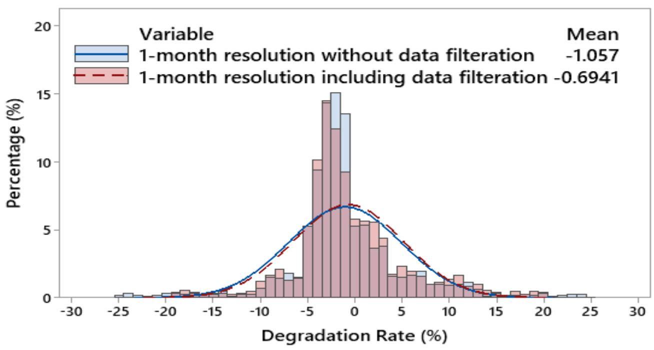
This technique requires not only the temperature variance of the PV site, as our technique does, but also requires the following steps: data normalisation, filtering row data and aggregation. Therefore, the data analytics of the "degradation rate estimation" strongly depends on the actual data available on the PV site; hence, more data available with more time-stamp (data captured using 1min resolution or less) would typically result in an accurate prediction of the degradation rate. However, as recommended by [35] the estimation of the PV degradation is more accurate if the data aggregation is of 1-week to 1-month resolution. Therefore, both aggregation processes were used to analyse our available dataset from the Plymouth site.

The results of the degradation using the RdTool is shown in Figure 7. As can be seen in Figure 7(a), the degradation rate of the PV site is equal to -1.176%/year without any data filtration; means that all aggregated data of the PV site is used for this analysis, while any missing data or inaccurate data has been considered. After the filtration process, which typically takes considerable time to do so, the degradation was as accurate as -7.77%/year, close to our previous findings of -0.74%/year as shown in Figure 2a. The results of 1-month resolution without any data filtration is shown in Figure 7(b), the estimated degradation is -1.057%/year, while the degradation is estimated at -0.69%/year after filtering the data samples.

In contrast with the above-mentioned results, the commonly used RdTool requires a significant effort of data filtration and aggregation in order to estimate as accurate as possible the degradation rate of PV installations. However, our proposed technique do not require this substantial amount of filtration of the missing data samples which makes the power-irradiance technique easy to adapt and simple to implement practically.



(a)



(b)

Figure 7. Degradation rate analysis for Plymouth city using RdTool [34]: (**a**) 1-week data resolution; (**b**) 1-month data resolution.

6. Conclusion

This article presented the analysis of the degradation rate for seven different PV systems installed in various locations across England, Scotland, and Ireland. It was found that the lowest PV degradation rate of -0.4% to -0.6%/year was obtained in the Irish PV sites. Higher PV degradation rate of -0.7% to -0.9%/year was observed in the PV sites located in England. Whereas the highest PV degradation rate of -1.0%/year was observed in cold areas such as Aberdeen and Glasgow, located in Scotland. The main reason that the PV systems located in cold areas had the highest degradation rate is due to the frequent hoarfrost and heavy snow affecting these PV systems, resulting in a reliability and durability problems in the affected PV modules.

Furthermore, in this article, we have analyzed the performance ratio (PR) for all examined PV systems, where it was found that the monthly mean PR for the PV systems located in Ireland and England is always higher than 87%, whereas PV systems located in Scotland had the lowest monthly mean PR in the range of 85% to 86%. In future, it is intended to compare our observations with various PV systems installed in diverse locations across the globe, therefore enabling us to analyse the degradation rate of PV systems affected by different weather conditions.

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